ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998, S.O. 1998*, c. 15 (Sched. B), as amended (the **OEB Act)**;

AND IN THE MATTER OF the Motion to review and vary EB-2022-0184 Decision and Order (Phase 2) related to the Customer Volume and Variance Account.

EPCOR NATURAL GAS LIMITED PARTNERSHIP

ARGUMENT-IN-CHIEF

REVIEW OF CUSTOMER VOLUME VARIANCE ACCOUNT

A. INTRODUCTION

1. On July 18, 2022, EPCOR Natural Gas Limited Partnership (**EPCOR**) filed an incentive rate-setting mechanism application with the Ontario Energy Board (**OEB** or **Board**), seeking approval for changes to rates that EPCOR charges for natural gas distribution in its Southern Bruce service area, effective January 1, 2023 (the **Application**). Among other things, the Application requested to establish a Customer Volume Variance Account (**CVVA**) in order to track the variance in revenue resulting from the difference between: (a) the average customer volume forecast based on the common assumptions set out in the Board-approved Common Infrastructure Plan (**CIP**) to serve the Southern Bruce area; and (b) the actual average customer volume from January 1, 2021 until December 31, 2028.

2. In Decision and Order EB-2022-0184 (**Decision EB-2022-0184**), the Board approved the CVVA but (a) limited EPCOR's recovery of the CVVA to 50% of the accumulated annual balance until the point where EPCOR's actual earnings reach 300 basis points below its return on equity (**ROE**) that underpinned EPCOR's rates established in EPCOR's 2018-2019 Custom Incentive Rate-Setting proceeding[1] (the **Risk Sharing Mechanism**); and (b) directed that the effective date of the CVVA be January 1, 2023.

[1] OEB Decision EB-2018-0264 [*2018-2019 CIRS (EB-2018-0264) Proceeding*].

3. On May 10, 2023, EPCOR filed a motion to review and vary Decision EB-2022-0184 (the **R&V Motion**). The Board issued a Notice of Hearing, Procedural Order No. 1 and Decision on Threshold Question and Request for Stay in respect of the R&V Motion on June 7, 2023 **(EB-2023-0140 PO #1)**, wherein the Board determined that EPCOR satisfied the threshold test set out in Rule 43.01 and that the issues raised in its R&V Motion are material enough to warrant a review of Decision EB-2022-0184 and which, if proven, could be expected to result in a material change to Decision EB-2022-0184.

4. This review process is not to revisit the appropriateness of establishing the CVVA. What the Board must review in this proceeding is: (ii) whether the Risk Sharing Mechanism should be set aside; and (i) the appropriate effective date of the CVVA – January 1, 2021 or January 1, 2023.

B. Risk Sharing Mechanism

5. At issue in this proceeding is <u>not</u> whether the CVVA should be approved but whether EPCOR's shareholder should bear the risk of a portion of the revenue variance resulting from Rate 1 and Rate 6 volume variances.

6. In EB-2023-0140 PO #1, the OEB directed that EPCOR address the following in its Argument-in-Chief:

> 1) References from the CIP Proceeding, and any additional precedents or argument bearing on this point to support EPCOR's statements in its Motion that the CIP Proceeding determined that the risk for variances from average consumption for Rate 1 and 6 customers lies entirely with ratepayers, and that the OEB was bound by this risk allocation for the 10-year initial rate term.

7. EPCOR's R&V Motion seeks to set aside the Risk Sharing Mechanism. In EPCOR's submission, the Board erred on two bases: (a) determining that the CVVA should be subject to 50/50 sharing between EPCOR's shareholders and customers; and (b) further directing that EPCOR only be entitled to recover the balance in the CVVA up to the point where its actual earnings reach 300 basis points below its ROE, with no recovery at all thereafter.

8. Both of these directions are inconsistent with the regulatory framework that was put in place and approved in prior proceedings, for a 10-year rate term, for expansion of service to the South Bruce Municipalities.

(a) The Regulatory Compact

9. The foundational principle of the "regulatory compact" stipulates that the utility is granted the right to provide a service in a particular area with the opportunity to earn a reasonable return on its investment and to recover its prudently incurred expenses. The utility must provide that service to all, in a consistent, non-discriminating manner at a fair and reasonable cost. The regulatory compact is not a static concept but must be applied in the specific legislative and policy forces that govern the specific context.[2] In *Atco Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*[3], the Supreme Court of Canada described the regulatory compact as follows:

> [62] Rate regulation serves several aims — sustainability, equity and efficiency — which underlie the reasoning as to how rates are fixed …
>
> [63] These goals have resulted in an economic and social arrangement dubbed the "regulatory compact", which ensures that all customers have access to the utility at a fair price — nothing more. … Under the regulatory compact, the regulated utilities are given exclusive rights to sell their services within a specific area at rates that will provide companies the opportunity to earn a fair return for their investors. In return for this right of exclusivity, utilities assume a duty to adequately and reliably serve all customers in their determined territories, and are required to have their rates and certain operations regulated…
>
> [64] Therefore, when interpreting the broad powers of the Board, one cannot ignore this well-balanced regulatory arrangement which serves as a backdrop for contextual interpretation. The object of the statutes is to protect both the customer and the investor …. The arrangement does not, however, cancel the private nature of the utility. In essence, the Board is responsible for maintaining a tariff that enhances the economic benefits to consumers and investors of the utility.[4]

10. In EPCOR's submission, the regulatory compact that governs its service to the South Bruce Municipalities was established through the unique competitive process for community expansion initiated by the Board, and the Board was bound to adhere to that regulatory compact in considering EPCOR's application for the CVVA. EPCOR submits that in a competitive process, such as the community expansion process, the regulatory compact is reflected in the bargain struck as a result of that process. The bargain that EPCOR proposed and was accepted by the Board is discussed in detail below.

11. As EPCOR establishes herein, in correctly disposing of the application for the CVVA, the Board cannot deviate from the rate-setting structure and incentives established in the prior

[2] *FortisAlberta Inc v Alberta (Utilities Commission)*, 2015 ABCA 295 [*FortisAlberta*] at para 9.
[3] 2006 SCC 4 [*Stores Block*]
[4] *Stores Block*, at paras. 62-64, citations omitted.

proceedings, which resulted in the rates to be charged for the 10-year rate stability period. However, for the reasons set out below, EPCOR submits that the Board did just that by:

(a) determining that the CVVA be subject to 50/50 sharing between EPCOR's shareholders and customers, which alters the risk profile upon which the original CIP was based; and

(b) further limiting collection of the CVVA amounts in reference to EPCOR's achieved ROE, which in turn re-writes the target ROE included in EPCOR's competitive proposal.

12. In EPCOR's submission, there is little factual disagreement regarding the processes and basis upon which its rates for the South Bruce Municipalities were set for the 10-year rate stability plan. Notably, OEB Staff agreed that the Board should approve the establishment of the CVVA for substantially similar reasons as set out by EPCOR.[5] There is agreement that forecast Rate 1 and 6 customer volumes are common assumptions in the CIP and that had Enbridge Gas (Union) been the successful proponent, its existing Normalized Average Consumption Variance Account (**NAC**) would have likely captured the same type of volume variances that EPCOR intends to record in the CVVA.[6]

13. However, consistent with the Board's EB-2023-0140 PO #1, EPCOR agrees that a complete factual understanding of these proceedings critically informs why the Board should set aside the risk-sharing mechanism.

14. EPCOR's South Bruce natural gas distribution service in the South Bruce Municipalities is the outcome of a generic proceeding commenced by the OEB to review opportunities for natural gas expansion (EB-2016-0004). That proceeding resulted in the OEB issuing Decision EB-2016-0004 Ontario Energy Board Generic Proceeding on Community Expansion (November 17, 2016), (**Decision EB-2016-0004**) wherein the OEB set out its policy intended to encourage competition in the provision of natural gas distribution service in unserved communities. It described the concept of allowing for a hearing of alternative, competing bids, as follows:

> Competing utility companies would be incented to provide rates favourable to customers in order to be selected as the preferred proponent of the expansion project. The selected proponent would

[5] OEB EB-2022-0184 Proceeding , January 26, 2023 [*EPCOR 2023 Rates Proceeding (EB-2022-0184) OEB Staff Submission*], p 3.
[6] *EPCOR 2023 Rates Proceeding (EB-2022-0184) OEB Staff Submission*, p 5.

> then be incented to maintain low rates in order to be attractive to potential customers which would in turn should [*sic*] increase its margins. A minimum rate stability period of 10 years (for example) would ensure that rates applied for are representative of the actual underpinning long-term costs. The utility would bear the risk for that 10-year period if the customers they forecast did not attach to the system. At present, once an expansion is approved, the utility bears little long-term risk if its forecasts were overly optimistic, or its actual costs higher than expected. The cost is absorbed into rates and paid for by other ratepayers.
>
> As mentioned above the rate stability feature of the framework introduces a discipline that significantly reduces the need to scrutinize a proponent's projected revenues. As the rates will be stand-alone and designed to cover the costs of the proposed expansion the existing customers will be held harmless. Overstated costs would lead to overstated rates and where there is competition for the approval, a proponent will risk not being chosen. Where there is no competition, a proponent will still be incented to have as low a rate as it can afford to encourage customers to connect and provide the return on the proponent's investment during the rate stability period. The proponent will also have to obtain approval to adjust rates beyond the rate stability period.
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> […]
>
> The OEB expects to refine the mechanisms and features of the framework described here through the adjudication of the initial applications and will seek submissions from applicants and affected parties on implementation matters within those applications.[7]

15. As is evident from Decision EB-2016-0004, the competitive process is itself intended to achieve consumer protection that would normally be achieved through the Board's rate-setting oversight – thereby significantly reducing the "need to scrutinize a proponent's project revenues." Therefore, the generic proceeding, the resulting competitive proceeding and subsequent rate applications within the 10-year rate period are inextricably bound, and resulting customer rates must be based on and informed by the parameters established in these proceedings.

16. As contemplated, the Board held a competitive process to determine which utility (EPCOR, or a competing proposal by Union (now Enbridge)), would receive Certificates of Public Convenience and Necessity (**CPCN**) for the South Bruce Municipalities in Proceeding EB-2016-0137/-0138/0139. To facilitate the selection of a successful proponent, the OEB established the CIP, which would serve as a relative proxy to allow the OEB to undertake a comparison of the proponents' stated revenue requirements on a set of common parameters. Herein, Proceeding EB-2016-0137/-0138/0139 is referred to as the "**CIP Proceeding**".

17. In the CIP Proceeding, on June 23, 2017, the OEB issued a Partial Decision and Procedural Order No. 6 (the **CIP PO #6 Partial Decision**), which addressed several preliminary issues and which also required both EPCOR and Union to participate in a joint session with OEB

[7] OEB Decision EB-2016-0004 [*Generic Expansion Proceeding (EB-2016-0004) Decision*], pp 20-21.

staff on July 13, 2017, to determine the technical parameters of a CIP, explaining the purpose of the CIP and associated parameters as follows:

> **Issue #4**
>
> The OEB has determined that ultimately a common format for applications will be required. The OEB will be issuing approved Filing Requirements that will inform interested entities of what will be expected of them in bringing forward servicing proposals in due course.
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> **At this juncture and in this case, the OEB sees merit in establishing common parameters for the proponents to use in determining their respective revenue requirements.** The OEB will establish a Common Infrastructure Plan (CIP) as the basis for the proponents to determine their respective revenue requirements. Full consensus between the proponents on the plan's "fit for purpose" design attributes is not required as the CIP will act as a relative proxy or sample plan to allow the OEB to undertake a comparison of the stated revenue requirements on a set of common parameters. The CIP will be used as the basis for the revenue requirement submissions.
>
> The OEB will require proponents to work with OEB staff to create a CIP to serve the South Bruce area and a standard set of assumptions regarding permissible rate adjustments during the rate stability period. The overarching policy objective of driving efficiencies and lowering controllable costs is to be considered in the identification of permissible rate adjustments.
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> **The proponents and OEB staff must also determine other parameters as necessary to allow the proponents to file an application based on the CIP that will facilitate a meaningful comparison of the proposals and embody the policy objectives pertaining to positive outcomes for customers previously described.**
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> Proponents will be required to base their revenue requirement proposals on the CIP and identified permissible rate adjustment criteria. However, the CIP is a tool for comparison, and will not necessarily represent the final distribution infrastructure which the successful applicant will construct to serve the communities. The successful proponent will be free to ultimately serve additional customers and communities beyond those specified in the CIP during the 10 year rate stability period but will bear the onus to demonstrate that its incremental revenue requirements are aligned on a unit metric basis with its revenue requirement stated for the CIP.
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> The OEB Staff shall provide a CIP and draft permissible rate adjustment criteria and proposal comparison criteria complete with any commentary it considers to be of assistance to the OEB subsequent to meeting with the proponents. The OEB will consider soliciting responding submissions from intervenors at that time. [Emphasis added.][8]

18. In CIP PO #6 Partial Decision, the OEB also directed EPCOR and Union to participate in a joint session with OEB staff to determine the technical parameters of the CIP and for OEB Staff to file an update with the Board regarding progress made in this joint session. This joint process determined the technical parameters of the CIP.[9]

19. Following this direction, OEB staff filed a Staff Report on July 20, 2017 (**CIP Staff Report**), which outlined areas of agreement and disagreement regarding the CIP parameters. Agreement

[8] OEB Proceeding EB-2016-0137, EB-2017-0138, EB-2017-0139 [CIP Proceeding], PO #6 Partial Decision, p 4-5.
[9] OEB Decision EB-2016-0137, EB-2017-0138, EB-2017-0139 [*CIP Decision*], p 3.

regarding the common assumption of customer consumption for mass market consumers was achieved and described as follows:

> *Customer Consumption*
>
> Proponents agreed to use the same value for the average annual usage of mass market consumers. Proponents agreed to work together to develop common consumption levels for each mass market segment, including residential, small/medium commercial, small/medium industrial, hospitals, schools and other municipal or institutional consumers.
>
> Proponents agreed that consumption levels forecast for any large commercial or industrial customers should not be set in common, but rather left to competition in each proponent's proposal.

20. Indeed, this is not a surprising result – as the Board is aware, Union operates with a variance account similar to that of the CVVA (its NAC), and it would have been inconsistent for Union to agree in the CIP setting process that it should bear some or all of the variance in customer consumption.

21. As is evident from the Customer Consumption parameter that was agreed upon, only volume associated with large commercial or industrial customers was considered to be set by competitive forces. Therefore, it was clearly the intention that other customer consumption (i.e., Rates 1 and 6) was not a parameter in respect of which the proponents (either EPCOR or Union) would be at risk in their CIP proposals.

22. This is further evident from the explicit agreement to treat customer attachments as an at-risk element in the CIP Staff Report:

> *Customer Attachments*
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> Both proponents agreed that the number of attachments should be competitive. Proponents agreed to file their own forecast of attachments as part of their proposals, and that the successful proponent would then be held to its forecast for rate making purposes. Proponents felt that they each might be willing to take on different levels of risk and marketing activities, and that setting the number of attachments as common would remove a significant component of the competition. Proponents felt that the proposed comparison metrics would illuminate any potential differences between their proposals and provide information on a levelized basis.

23. There is no similar statement that mass customer volumes should be competitive and that proponents would be willing to take on the risk of such volumes in the Staff Report.

24. In the CIP Decision on Preliminary Issues and Procedural Order No. 8 (August 22, 2017) (**CIP PO #8**), the Board held as follows (at pp 3-4):

> The OEB recognizes that both proponents have agreed to certain assumptions regarding CIP parameters. The common assumptions of the CIP should be explicitly included in each proponent's proposal to ensure that proponents are adhering to their agreement. However, the OEB does not expect proponents to disclose those competitively derived elements that build up the revenue requirement.
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> *Agreed Upon Parameters*
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> A full description of the parameters that were agreed upon can be found in the OEB Staff Report filed on July 20, 2017. The OEB has summarized the agreed upon parameters below and finds that they are appropriate:
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> […]
>
> - Customer Consumption
>
> The OEB accepts this aspect of the CIP agreement and finds that using common consumption levels for each mass market segment, except for large commercial or industrial customers, is appropriate. The proponents agreed to work together to develop these values. These values should be included in proponents' proposals. If the proponents are unable to agree on the values to be used, they may seek further directions from the OEB.[10]

25. Of fundamental importance to this process was that the CIP was intended to "allow the OEB to undertake a comparison of the proponents' stated revenue requirement on a set of common parameters."[11]

26. Union and EPCOR worked cooperatively to reach agreement on the average annual consumption levels for the mass market customers. On October 2, 2017, Union and EPCOR filed a letter to advise the Board of the details of agreed parameters, including mass market Customer Consumption:

> Customer Consumption
>
> The following annual average consumption values for forecasted mass market customer attachments will be incorporated in the calculation of annual revenue requirements:

Segment/Sub-Segment		**Average Annual Consumption (m3/year)**
Residential	Pre-existing homes	2,149
	Future Construction	2,066
Commercial	Small (0-1,500 m3/year)	4,693
	Medium (15,001-50,000 m3/year)	26,933
	Large (>50,000 m3/year)	75,685
Agricultural	Cash Crop Farm (excl. large grain dryers)	4,720
	Other Agri-Business	4,720

[10] *CIP Decision*, p 1.
[11] *Generic Expansion Proceeding (EB-2016-0004) Decision*, p 1.

> For the above segments, in the year each specific customer attaches, the volume will be 50% of the above figure. Industrial, large grain dryer, and poultry or other similar large farm consumption values will vary for each proponent, and their volumes in the year of connection will be based on expected connection timing for those customers.
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> […]
>
> Both proponents have agreed upon the above values and will apply them in their respective CIP proposals.

27. Both EPCOR and Union filed their respective CIP Proposals using these average consumption values as common parameters for these mass market customers.[12] As explained by EPCOR in EB-2022-0184, the common assumptions regarding annual customer volume for mass market customers were based on Union's then current normalized average consumption per customer for its adjacent markets.[13] EPCOR submits that at the time of the CIP Proceeding, consumption information from Union's adjacent markets was the most readily available and reliable source of data. As evidenced by the agreement of OEB Staff to this common assumption, there was no better volume forecast available at the time and its use was demonstrably reasonable to provide the basis for the rates that would be subject to a 10-year rate stability period. In fact, the use of anything else would have been arguably unreasonable.

28. The establishment of the CIP was meant to serve as a proxy to allow the OEB to compare revenue requirements on a set of common parameters.[14] An underlying principle of the approved CIP was that, within the framework as established by the Board, the winning proponent would bear the risk of achieving commitments made related to certain parameters. The parameters that were expressly identified as being determined by competition were: infrastructure specifications and costs; number of customer attachments; the timing of customer connections each year; customer consumption for large commercial or industrial customers; cost of debt and ROE.[15] Based on a reading of the EB-2016-0137/138/0139 Decision and Order, as well as the record of the proceeding, it is clear that treatment of these parameters was at the successful utility's risk – if the utility exceeds the values of those components during the rate stability period this would be to the benefit, or in the case of expenses, detriment, of the utility.

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[12] *CIP Proceeding*, Union CIP Proposal (October 16, 2017), p 20-21; *CIP Proceeding*, EPCOR CIP Proposal (October 16, 2017), p 21.
[13] OEB Decision EB-2022-0184 [Decision EB-2022-0184], p 14.
[14] *CIP Decision*, p 7
[15] *CIP Decision*, pp 8-9.

29. In the OEB reasons, mass customer volumes were not identified as a competitive factor, consistent with CIP PO #8:

> • **Customer Consumption**: Proponents were to use common consumption levels for each mass market segment, except for large commercial or industrial customers, which were to be left to competition.[16]

30. Using the CIP parameters, the proponent utilities submitted proposals that were evaluated on the basis of three agreed-upon criteria: cumulative 10-year revenue requirement per unit of volume ($/m3), customer years, and cumulative 10-year volume. These criteria were reviewed to provide a potential check against gaming the revenue requirement metrics associated with under-estimated capital and OM&A expenses.[17] As it relates to capital structure, as noted above – the capital structure was a common assumption based on Union's debt/equity ratio of 64%/36%. However, cost of debt and return on equity were considered competitive elements. Therefore, Union and EPCOR did not disclose their assumed cost of debt and return on equity in their CIP proposals.[18] Instead an overall revenue requirement, which aligned with the CIP parameters and did not provide detail on competitive elements was presented by EPCOR and Union.

31. In its decision on the CIP Proceeding, the OEB determined that EPCOR was the successful proponent and awarded EPCOR the CPCN for the South Bruce Municipalities. In so doing, the Board directed that:

> Given the competitive nature of this process, the OEB will require EPCOR to demonstrate that forthcoming leave to construct and rates applications are consistent with its CIP proposal.[19]

32. Therefore, at the conclusion of the competitive process, the OEB was clear that resulting distribution rates must be consistent with the framework and commitments included in the approved CIP.[20]

33. On April 11, 2019, EPCOR filed a 2019-2028 custom incentive ratemaking (**CIR**) application with the OEB under section 36 of the *Ontario Energy Board Act*, seeking approval for rates that EPCOR can charge for gas distribution service to the South Bruce Municipalities (EB-2018-0264). Consistent with the competitive parameters of its CIP proposal and the Board's

[16] *CIP* Decision, p. 8.
[17] *CIP Decision*, p 11.
[18] *CIP Proceeding*, EPCOR Proposal (April 12, 2018), p 8. In the Decision and PO # 8, the OEB agreed that proponents would not have to disclose certain information involving competitively derived elements that build up the revenue requirement in the proposals, p 3.
[19] *CIP Proceeding*, South Bruce Expansion Applications, Decision and Order (October 16, 2017), p 9.
[20] *CIP Decision*, Section 4.2 Assessment of CIP Proposals, p 11,

decision in EB-2016-0137/0138-0139, EPCOR's CIR application was consistent with its CIP proposal and its commitments therein. For example, volumes for large commercial and industrial customers and customer attachments in the CIR were as detailed in EPCOR's CIP.[21]

34. Similarly, the target values for ROE included by EPCOR in its CIP proposal were "as defined by EPCOR and represents the target values EPCOR deemed to be acceptable for this project" as this was a competitive parameter.[22] For the purposes of its CIR application, EPCOR provided its forecast cost of capital from 2018 to 2028 consistent with the parameters used in EPCOR's CIP submission.[23] It was therefore understood and approved by the Board that as part of the regulatory framework for providing service to the South Bruce Municipalities, EPCOR ought to have a reasonable opportunity to achieve the ROE included in its CIP proposal (8.78%) over the 10-year rate stability period, while taking into account that EPCOR was at risk for certain competitively determined parameters within that framework.

35. However, customer consumption for Rates 1 and 6 customers was not one of the competitive parameters. With respect to the volume risk assumed by EPCOR and the common assumption regarding customer consumption, in the CIR EPCOR stated:

> As an expansion project, there is no historical information available for comparison purposes or determining accuracy with previous forecasts. EPCOR notes that as per the CIP process, the utility is assuming volume risk within the assumption framework of that process.[24] [Emphasis added.]

36. Again, it was accepted and understood that the volume risk was as determined in the CIP Proceeding, which made only the large industrial and commercial customer consumption a competitive parameter and subject to utility risk – mass customer consumption (Rates 1 and 6) was not. Indeed, the OEB Staff agrees that "there was no better volume forecast available at the time of EPCOR's 2019-2028 Custom IR proceeding than Enbridge Gas's then current normalized average consumption per customer for its adjacent markets."[25]

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[21] *2018-2019 CIRS (EB-2018-0264) Proceeding*, EPCOR Exhibit 1, April 12, 2019 at para. 12; EPCOR Exhibit 3, April 12, 2019, Section 3.1 at paras 1-7.
[22] *2018-2019 CIRS (EB-2018-0264) Proceeding*, EPCOR Exhibit 1, April 12, 2019 at para 12 *2018-2019 CIRS (EB-2018-0264) Proceeding* , EPCOR Exhibit 5, April 12, 2019, Section 5.2 at para 1.
[23] *2018-2019 (EB-2018-0264) CIRS Proceeding* , EPCOR Exhibit 1, April 12, 2019 at para 12; *2018-2019 CIRS (EB-2018-0264) Proceeding* , EPCOR Exhibit 5, April 12, 2019, Section 5.2 at paras 2-3.
[24] *2018-2019 CIRS (EB-2018-0264) Proceeding* , EPCOR Exhibit 3, April 12, 2019, Section 3.3 at paras 1.
[25] *EPCOR 2023 Rates Proceeding* (EB-2022-0184) *OEB Staff Submission* , p 9.

37. Therefore, while EPCOR could theoretically have brought forward a proposal at the time of the CIR application to implement the CVVA, it did not at that time have volume data or information that would have served to support the basis for the implementation of the CVVA. This is in distinction to the Energy Content Variance Account (**ECVA**) that EPCOR proposed and the OEB approved in that proceeding. The ECVA records any variations in revenues and costs resulting from differences in the energy content of the gas actually delivered and the assumed energy content. In EB-2018-2064, EPCOR provided evidence of the energy content for gas in the delivery area changing over time.[26] In contrast, as acknowledged by OEB staff, EPCOR did not have similar evidence of actual mass customer consumption differing from the common assumptions that formed the basis of the CIP. Therefore, any suggestion that EPCOR should have brought forward the CVVA in the CIR proceeding[27] is without any factual basis.

38. Also, in approving the ECVA applied-for by EPCOR, the Board confirmed that customer volumes were not a factor upon which proponents accepted risk in the CIP Proceeding and that Enbridge (Union) had variance accounts for consumption volumes:

> The OEB concludes that a variance in energy content of natural gas is outside of what was considered for the CIP, therefore the OEB approves the [Energy Content Variance Account]. EPCOR Southern Bruce developed the common average use assumptions for each market with Union Gas (now Enbridge Gas) during the CIP process. These projections were based on Union Gas' average use per customer. The OEB notes that Enbridge Gas has variance accounts to record changes in average use that captures changes in consumption volumes due to among other things changes in the heat content, for both the Enbridge Gas Distribution and Union Gas rate zones.[28]

39. Although OEB Staff opposed the ECVA account in Proceeding EB-2018-0264, erroneously arguing that EPCOR has assumed volume risk as part of the CIP, in Proceeding EB-2022-0184, OEB Staff agreed that the OEB <u>should</u> approve the establishment of the CVVA:

> OEB staff agrees with EPCOR that the forecast Rate 1 and Rate 6 customer volumes are common assumptions in the CIP. OEB staff also agrees with EPCOR that had Enbridge Gas been the successful proponent its existing NAC account would have likely captured the same type of volume variances that EPCOR intends to record in the CVVA. Therefore, OEB staff submits that the OEB should approve the establishment of the CVVA, with certain modifications.[29]

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[26] *2018-2019 CIRS (EB-2018-0264) Proceeding* , Interrogatory Responses from the Applicant, July 5, 2019, 9.Staff.37, p 1.
[27] *EPCOR 2023 Rates Proceeding (EB-2022-0184) OEB Staff Submission* , p. 9.
[28] OEB Decision EB-2018-0264 [*2018-2019 CIRS (EB-2022-0184) Decision*], , pg. 20-22
[29] *EPCOR 2023 Rates Proceeding OEB Staff Submission* , p. 5, citing OEB Decision EB-2016-0137. Footnotes omitted.

40. It is therefore abundantly clear from the foregoing that mass customer consumption (Rates 1 and 6) was outside the competitive CIP parameters, not subject to utility risk and therefore subject to adjustment to address variances in the course of the 10-year rate stability period.

41. EPCOR acknowledges that the CIP Proceedings do not expressly state that "risk for variances from average consumption for Rate 1 and 6 customers lies entirely with ratepayers"; however, this conclusion is the clearly implied basis upon which the CIP framework and parameters were established. Were EPCOR to be at risk for such amounts, then that would not have been a common assumption, it would have been a competitive assumption, and EPCOR would have had to properly take achievement of such a competitive assumption into account in submitting its target ROE in the CIP Proceeding. This is the correct manner in which to interpret the CIP and is supported by the context of that proceeding. Particularly, as noted above, the Board specifically directed EPCOR, Union and OEB staff to determine parameters for the CIP that would allow *the proponents to file an application based on the CIP*:

> The proponents and OEB staff must also determine other parameters as necessary to allow the proponents to file an application based on the CIP that will facilitate a meaningful comparison of the proposals and embody the policy objectives pertaining to positive outcomes for customers previously described.[30]

42. These parameters were subsequently adopted by the Board in CIP PO#8. The foregoing makes it clear that as directed by the Board, the parties to the CIP Proceeding expressly turned their minds to mass customer consumption as a CIP parameter, and identified those parameters would not be competitive (i.e., not a utility risk). Given the specificity of the Board's direction and the clear consideration of customer consumption (the identification that large commercial and industrial would be competitive and the mass customer consumption would be common, i.e., not competitive), the clear conclusion is that mass customer consumption was not intended to be a competitive factor and therefore, not a utility risk. The force of this conclusion is unassailable given the evidence that the parties to the CIP Proceeding expressly turned their minds to this issue in response to a Board direction.[31]

43. Further, the CIP Proceeding and approved framework were abundantly clear that EPCOR, and by extension the Board, are bound by this risk allocation for the 10-year initial rate term.

[30] *CIP Proceeding*, PO#6 and Partial Decision, p 4.
[31] This is similar to the principle of statutory interpretation of *expressio unius est exlusio alterius*. An express statutory mention of one item is presumptively exhaustive and impliedly excludes other similar items: Ruth Sullivan, Sullivan and Driedger on the Construction of Statutes, 4th ed. (Markham, Ontario: Butterworths, 2002), 186-94.

EPCOR was required to submit its CIR consistent with the CIP parameters and its commitments in the approved CIP.[32] EPCOR could not therefore deviate and include a higher target ROE than that which formed the basis of its CIP proposal in its CIR application. It also could not have proposed a variance account for number of customer attachments, or any other competitive factor. Conversely, it was likewise not open to the Board during the CIR proceeding, and is not currently open to the Board, to set a new ROE for EPCOR in setting rates for the South Bruce Municipalities or introduce new incentives or efficiency factors that were not part of the approved CIP.

44. The foregoing regulatory proceedings and framework are the "regulatory compact" struck, in the context of the generic proceeding initiated by the Board and the resulting unique rate proceedings to determine the proponent to extend service to the South Bruce Municipalities. In considering this "regulatory plan" or "compact" approved pursuant to EB-2016-0004, EB-2016-0137/0138/0139, and EB-2018-0264 (collectively, these proceedings are referred to as the "**CIP Process**"), several things are apparent:

(a) The CIP Process identified competitive parameters and these were determined in that process; therefore, the resulting framework and CIP Parameters reflect the agreed upon extent of embedded efficiency and incentives. In this regard, EPCOR's CIP proposal set out its proposed cumulative 10-year revenue requirement, which was arrived at via EPCOR incorporating cost control and built-in incentives in order to maintain the most favourable cost structure.[33] Therefore, the CIP Process has already resulted in a revenue requirement that incorporates productivity and stretch factors, and to apply additional incentive factors after-the-fact results in a doubling up on these elements.[34]

(b) As the successful proponent, EPCOR's rates during the 10-year rate stability period must be <u>consistent</u> with the revenue requirement submitted in the CIP proposal and which resulted in it being selected as the successful proponent.

[32] *CIP Decision*, Section 4.2, p 5, 11, *CIP Proceeding*, Decision on Issues List, August 20, 2019, p 3; see also, *2018-2019 (EB-2018-0264) CIRS Decision*.
[33] *2018-2019 (EB-2018-0264) CIRS Proceeding,* EPCOR Response to OEB 10.Staff.40 (July 5, 2019) at p 139-140.
[34] *2018-2019 (EB-2018-0264) CIRS Proceeding,* Application Exhibit 10 (October 3, 2018) at p 3.

(c) The CIP Process established the framework for the transfer of risk to the utility, as contemplated in that competitive process (which includes commitments to protect the rate payer against cost overruns related to the material capital expenditures necessary to construct the system, control of OM&A expenditures and achievement of ROE).

(d) While one of the basic principles of the competitive process was that proponents would take the risk of achieving an acceptable return, this risk was accepted, and incorporated into EPCOR's CIP proposal, based on the established CIP parameters and framework.

45. Nonetheless, in Decision EB-2022-0184, the Board either ignored, failed to apply, deviated from or altered this established and approved framework for EPCOR's distribution rates for the South Bruce service area, by limiting recovery of amounts recordable in the CVVA. In so doing, the Board committed errors of fact or law, and in effect, failed to uphold the applicable regulatory compact.

46. EPCOR acknowledges that it proposed an alternative to the proposals of the Interveners should the Board determine that a risk sharing mechanism was necessary.[35] However, this proposal was in the spirit of a voluntary compromise, and it proposed a risk apportionment whereby existing customers would share 50/50 in the consumption variances and new customers (after September 1, 2022) would bear 100% of the consumption volume risk. The OEB rejected that voluntary proposal.

47. However, by rejecting this voluntary proposal, the Board did not acquire jurisdiction to alter or ignore the CIP, and its prior decisions, which provide the framework for EPCOR's rates over the ten-year rate stability period. Yet, in EPCOR's submission, this is what the Board did and as further particularized below, in so doing, was in error.

(b) The Risk of the Mass Customer Consumption variances was not an unsettled issue

48. Approval of the CVVA itself leaves the CIP parameters unaltered and is consistent with the CIP, EPCOR's CIP proposal and therefore, the resulting CIR approved in EB-2022-0184.

[35] See *EPCOR 2023 Rates (EB-2022-0184) Proceeding,* EPCOR Reply Argument, February 13, 2023 at paras 51-57..

There is no disagreement that the CVVA itself is appropriate and that is not at issue in this proceeding. What is at issue is whether the Board erred in determining that volume variances are a shared risk.

49. While EPCOR agrees with the Board that the CIP volume risk was not directly addressed in the CIR decision EB-2018-0264,[36] EPCOR disagrees with the Board's implication that it was therefore not a decided issue. As EPCOR has detailed above, mass customer consumption was a live issue during the CIP Proceeding and a matter that EPCOR, Union and Board staff expressly considered in that process, reaching agreement upon its treatment as a common assumption. It was not identified as subject to competition, and therefore, was not an item that the CIP approved framework intended to be a utility risk, as approved in the CIP Proceeding. Although the risk of consumption variances was not discussed in the CIR proceeding, it had already been decided in the prior EB-2016-0137/0138/0139 proceeding.

50. Therefore, the Board's conclusion that the risk of variances for mass customer consumption volumes "was not a live issue"[37] and therefore implying it was undecided and remained unsettled, is an error of fact or mixed fact and law in understanding and applying the approved CIP process and parameters in Decision EB- 2022-0184.

(c) Failing to consider the applicable Regulatory Compact

51. The Board's error in concluding that the risk of variances for mass customer consumption was unsettled, highlights other errors of the Board. As set out in EPCOR's R&V Motion, the Board ignored the CIP Proceeding and the applicable regulatory compact. In so doing, the Board failed to appreciate the binding nature of the CIP Proceeding on EPCOR's distribution rates for the South Bruce service area (which is an error law) or failed to consider relevant factors (the parameters of the CIP Proceeding) in rendering its decision, which is likewise an error of law.[38] As noted in the R&V Motion, the Board's failure to consider and follow the CIP Proceedings (EB-2016-0004, EB-2016-0137/0138/0139, and EB-2018-0264) is not an issue of *stare decisis*.[39] Rather, the CIP Proceedings are more than just comparable facts but are in fact valid and binding

[36] *EPCOR 2023 Rates* Decision EB-2022-0184 , p 16.
[37] Decision EB-2022-0184, p 16..
[38] See *ENMAX Power Corporation v. Alberta Utilities Commission*, 2021 ABCA 347 at paras 20-21.
[39] *EPCOR 2023 Rates Proceeding,* Notice of Motion to Review and Vary (May 10, 2023) [*R&V Motion*] at para 19.

Board directions that must be implemented in EPCOR's distribution rates for the South Bruce service area. Therefore, the Board was bound to follow that framework.[40]

52. In failing to follow these previous decisions, the Board failed to implement the underlying utility-customer risk sharing framework as it relates to the risk of customer consumption variances. More specifically, the Board did not implement the CVVA in a manner consistent with the CIP Proceeding, where-in it was expressly determined that mass customer consumption was not a risk that the utility needed to address in its CIP proposal. Instead of assessing the CVVA request in terms of whether it was appropriate and compatible with the CIP Proceedings, the Board instead proceeded to generically determine that a 50/50 split was "appropriate" in a case where no party bears all of the fault.[41] This amounts to an error of law because the Board failed to apply the correct legal framework. Indeed, the Board's reasoning in Decision EB-2022-0184 does not explain (nor did it apparently turn its mind to) how a 50/50 split was consistent with the parameters established in the CIP Proceeding and which EPCOR was bound to apply and follow in its CIR application).

53. In EPCOR's submission, the Board's errors in this regard are a sufficient basis upon which the Rate Setting Mechanism ought to be set aside.

(d) Altering the Regulatory Compact by Introducing a New Risk Parameter

54. In addition, the Board's determination that a 50/50 sharing mechanism should be applied to the CVVA in effect introduces a <u>new</u> parameter for which the utility now bears some risk. As explained in EPCOR's R&V Motion, the Board committed an error of law by altering the risk allocation (for customer consumption variances) set out in the CIP Proceeding. Instead of being a risk element borne by customers entirely (as contemplated by the CIP Proceeding), the Decision states that the risk should be shared equally between shareholders and customers because "neither should be entirely responsible."[42]

55. Board decisions and orders are final and a decision cannot be revisited simply because the tribunal has changed its mind.[43] Although the Board has procedures to review prior decisions,

[40] This is also analogous to an administrative tribunal ignoring applicable guidelines, which the Supreme Court of Canada has held provides grounds for determining a tribunal's decision is reviewable as not being reasonable: *Baker v. Canada (Minister of Citizenship & Immigration),* [1999] 2 S.C.R. 817 (S.C.C.),
[41] Decision EB-2022-0184,p 17.
[42] *R&V Motion* para 24.
[43] Lorne Sossin, Robert W. Macaulay, James L.H. Sprague, "Practice and Procedure Before Administrative Tribunals", § 35:2.

such a procedure was not invoked in EB-2022-0184. Therefore, the utility-customer risk sharing framework as it relates to the risk of customer consumption variances must continue to be applied as established in the CIP Proceedings.

56. Furthermore, to alter the CIP proceeding framework by adding a new utility risk parameter is manifestly unfair. As noted in the Affidavit of Ms. Robinson, EPCOR was not previously expected to assume any portion of this risk and nor did it plan for this sharing outcome in building the system and connecting customers.[44]

57. The parameters established in the CIP Proceedings are binding with respect to rate-setting in the ten-year rate stability period. The CIP Proceeding, the CIR Proceeding, and any other rate proceeding in the ten-year rate stability period must be consistent with respect to the treatment of the CIP parameters throughout that timeframe. Decision EB-2022-0184 establishes no basis upon which the Board could properly exercise its jurisdiction to review past decisions, and materially change the risk allocation set in the CIP Proceedings in the midst of the ten-year rate stability term. Indeed, in EB-2018-0264, the Board held that matters not included as criteria in the CIP process were not available during the 10-year rate stability period.[45]

58. Therefore, because the effect of Decision EB-2022-0184 is to introduce a new risk parameter, it discloses an error of law. EPCOR submits that this error provides a further basis upon which the Rate Setting Mechanism should be set aside.

(a) Altering the Regulatory Compact by Modifying EPCOR's ROE

59. Similar to the Board's determination that mass customer consumption should be a shared risk, EPCOR likewise submits that the Board's decision to modify the CVVA to tie recovery to EPCOR's achieved ROE is likewise contrary to the CIP Proceedings. In Decision EB-2022-0184, the Board held that EPCOR's ability to recover amounts recorded in the CVVA would only apply until such time as EPCOR's actual earnings reach 300 basis points (**-300 bp**) below its target ROE.[46] As EPCOR understands the Board's decision, if recovery of the amounts in the CVVA result in EPCOR earning an actual ROE over this -300 bp threshold, EPCOR will not be permitted to receive any such amounts.

[44] EB-2023-0140, Affidavit of Susannah Robinson (May 10, 2023) at para 28.
[45] Decision EB-2022-0184, p 25.
[46] *EPCOR 2023 Rates Decision*, p 16.

60. The -300 bp modification introduces a means test to the recovery of the CVVA variance amounts. The effect of imposing this means test is to rewrite or modify the target ROE that was the basis of EPCOR's CIP proposal and was therefore required to be incorporated into its CIR application. Again, changing the circumstances in which EPCOR is permitted to recover its ROE is in effect a change to the CIP framework, undertaken after-the-fact and within the 10-year rate stabilization period. This is contrary to the basis upon which EPCOR participated in the CIP process and submitted its CIP proposal to serve the South Bruce Municipalities. As outlined above, EPCOR's CIP proposal was submitted on the basis that mass customer consumption was not a utility risk and a target ROE of 8.78%. The bargain struck was that EPCOR's ability to achieve its target ROE would depend on the competitively determined parameters (i.e., customer connections, etc.). By introducing the -300 bp threshold on CVVA recovery, the Board is in effect after-the-fact reducing the actual ROE that EPCOR can achieve due to a factor unrelated to EPCOR's ability to meet its forecasts for the CIP competitive parameters.

61. The Board justified its imposition of the -300 bp threshold on the basis that it would "incent EPCOR to act to improve capital asset utilization and EPCOR's resulting ROE forecast from 2023 to 2028."[47] Applying the -300 bp threshold is inconsistent with the CIP Process as it purports to introduce a new incentive. As discussed above, EPCOR's CIP proposal was arrived at via EPCOR incorporating cost control and built-in incentives in order to maintain the most favourable cost structure. Indeed, as part of the settlement proposal reached and approved by the Board in the CIR Proceeding, it was agreed that "the **exclusion** of a productivity factor, stretch factor, earnings sharing mechanism and an earnings dead-band off-ramp are **consistent** with EPCOR Southern Bruce's CIP proposal."[48] The Board expressly found that that the settlement proposal was consistent with EPCOR's CIP proposal.[49] In addition, the Board determined in the CIP Proceeding that ROE was a competitive component. The built-in incentives that were part of the CIP proposal combined with the fact that the utility has accepted risk regarding achievement of its ROE does not align with having an -300 bp threshold on recovery of amounts in the CVVA.

62. An objective of the competitive process was to enable expansion of natural gas distribution into regions that have been previously unserved while ensuring that rate payers are charged rates

[47] Decision EB-2022-084, p 16.
[48] *2018-2019 (EB-2018-0264) CIRS Proceeding*, Decision on Settlement Proposal and Procedural Order No. 6 (October 3, 2019), Schedule A, PDF 38.
[49] *2018-2019 (EB-2018-0264) CIRS Proceeding*, Decision on Settlement Proposal and Procedural Order No. 6 (October 3, 2019), Schedule A, PDF 8.

that reflect the best value. As stated by the Board: "The primary benefit of the introduction of competition identified in the generic decision is the discipline it instills to control costs and the search for efficiencies in system expansion and operation."[50] In other words, the competitive tension inherent in the OEB's process required competing proponents to include efficiencies and built-in incentives in their CIP proposals. The OEB also introduced a 10-year rate stability period. A driver of the stability period was to shift risk that is typically born by the ratepayer to the utility. EPCOR bears the risk during the 10-year period of both: (a) fewer customer attachments than forecasted or higher OM&A costs; and (b) capital cost overruns.[51] In this regard, EPCOR has incurred capital overages of approximately $13 million for infrastructure and has accepted full responsibility for the financial implications of this competitive parameter as outlined in the CIP parameters and its CIP proposal.[52] In summary, the CIP Process required the successful proponent of a system expansion to exercise discipline to control costs and search for efficiencies while also being incented to keep its rates low as this could lead to increased ROE for that utility during the 10-year rate stability period. Therefore, the CIP Process has already resulted in a revenue requirement that incorporates competitively determined incentives and to apply additional incentive factors after-the-fact results in a doubling up on these elements.

63. As discussed above with the 50/50 risk sharing for the CVVA recovery, in applying the -300 bp threshold, the Board did not turn its mind to, failed to apply or ignored the applicable legal framework in assessing whether it was appropriate to impose the -300 bp threshold on CVVA recovery. What the Board should have asked was whether imposing that -300 bp threshold was consistent with the parameters and commitments established in the CIP Proceedings (EB-2016-0004, EB-2016-0137/0138/0139, and EB-2018-0264). The Board did not do so. Instead, the Board considered whether the -300 bp threshold was reasonable and would provide EPCOR with a reasonable opportunity to earn a fair return. As discussed in more detail below, the -300 bp threshold is neither. Regardless, however, this is the wrong inquiry, which is an error of law.

64. EPCOR submits that the Board made similar errors as outlined above, and in fact, compounded its errors by tying EPCOR's ability to recover the CVVA variances to EPCOR's achieved ROE. In failing to follow the CIP Proceeding decisions, the Board failed to implement the underlying utility-customer risk sharing framework as it relates to EPCOR's ability to achieve

[50] *CIP Proceeding*, PO#6 and Partial Decision, p 3.
[51] *2018-2019 (EB-2018-0264) CIRS Proceeding,* EPCOR Response to OEB 10.Staff.40 (July 5, 2019) at p 140.
[52] EB-2023-0140, Affidavit of Susannah Robinson (May 10, 2023) at para 17.

its ROE. More specifically, the Board did not implement the CVVA in a manner consistent with the CIP Proceeding, wherein it was expressly determined that EPCOR's ability to achieve its target ROE would be dependent on the competitively determined parameters (i.e., customer connections, etc.). The -300 bp threshold restricts EPCOR's ability to achieve its target ROE based on a hitherto unidentified risk.

65. Therefore, because the effect of Decision EB-2022-0184 is to change the framework applicable to EPCOR's ability to achieve its target ROE, the Decision discloses an error of law. EPCOR submits that this error provides a further basis upon which the Rate Setting Mechanism should be set aside.

(b) The Board's errors result in a material impact on EPCOR

66. Finally, the implications of the Board changing the rules of the game in this fashion are apparent. Essentially, EPCOR would have the possibility of achieving an average ROE of -0.2% over the ten-year period, if the CVVA is approved as proposed by EPCOR. This demonstrates that in honouring the regulatory compact established by the CIP Proceeding, EPCOR is already at risk for a significant financial loss. Under the Board's Risk Sharing Mechanism, the possible achieved ROE is reduced to -1.8%, which is below an acceptable rate of return by any standards.[53] EPCOR submits that the financial impacts of the Risk Sharing Mechanism serve to validate that the Board erred in imposing the Risk Sharing Mechanism. It is unassailable that the imposition of the Risk Sharing Mechanism has a material impact on EPCOR's ability to achieve any positive ROE over the 10-year term, let alone its target ROE upon which its CIP proposal was based.

67. If the Decision is corrected, and the Risk Sharing Mechanism set aside, the amounts that EPCOR would have the opportunity to recover through the CVVA would be materially different than the amount provided for in the Decision and would actually enable the utility some opportunity to earn a fair and reasonable return on its capital investments.

C. Other Grounds

68. In addition, the Board requested that EPCOR address the following:

[53] EB-2023-0140, Affidavit of Susannah Robinson (May 10, 2023) at paras 25-26.

> Advise the OEB if the grounds for the relief requested by EPCOR in this proceeding are based solely on a finding that the EB-2022-0184 Decision failed to give effect to the terms of the regulatory deal or compact that EPCOR alleges was formed in the CIP Proceeding. If any grounds for the relief requested by EPCOR stand independently of a finding that there was a regulatory deal or compact to which the EB-2022-0184 Decision failed to give effect, set out the basis for any claim for relief made by EPCOR that stands even if there was no regulatory deal or compact.

69. Even if there is no "regulatory deal or compact", the reasons provided by the Board to implement the Risk Sharing Mechanism and the CVVA effective date of January 1, 2023 are flawed and demonstrate that the Board erred.

(a) The Risk Sharing Mechanism is Punitive

70. First, even if the proper regulatory framework for establishing the CVVA was the general standard of setting "just and reasonable rates", the Board's reasoning for imposing the Risk Sharing Mechanism does not withstand scrutiny.

71. In this regard, the Board concludes that limiting EPCOR's recovery to 50% of the variance for customer consumption but only to the point that EPCOR's actual earnings reach 300 basis points below the ROE that underpinned EPCOR's CIP proposal, will "incent EPCOR to act to improve capital asset utilization and EPCOR's resulting ROE forecast from 2023 to 2028." EPCOR submits that in order for an incentive to be fairly implemented in a rate-making context, the inventive must be logically connected to performance and operational costs within the utilities control. In reality, however, EPCOR has little control over mass customer consumption.[54] As noted in the affidavit of Ms. Robinson filed in support of the R&V Motion, "there is only so much a utility can do to incentivize customers to incur the personal expense of installing natural gas appliances in their homes or consume more gas."[55] Behind the meter consumption and the personal choices of mass customers is not something within EPCOR's control. It is further unconnected to EPCOR's ability to find efficiencies and lower costs. Therefore, EPCOR submits that the Board's conclusion that the Risk Management Mechanism will provide an appropriate "incentive" to EPCOR is an error.

72. Indeed, the Board's reasoning provides no basis for the conclusion that the Risk Sharing Mechanism will incent "improved capital asset utilization."[56] The capital asset utilization risk that EPCOR does bear, and over which it does have control, is customer attachments. EPCOR is

[54] EB-2023-0140, Affidavit of Susannah Robinson (May 10, 2023), at para 28.
[55] EB-2023-0140, Affidavit of Susannah Robinson (May 10, 2023), at para 29.
[56] Decision EB-2022-084, p 16.

already incented to increase customer attachments, and EPCOR is on target to meet the Rate 1 customer capital connection targets upon with its CIP proposal was based by August 2023. [57] However, more attachments does not address the underlying purpose of the CVVA which is customer consumption once connected. The Board's reasoning does not demonstrate how EPCOR can implement measures to mitigate customer consumption variances. Therefore, the Board's comments that its Risk Sharing Mechanism is justified on the basis of providing an "incentive" is not credible.

73. Furthermore, the record clearly demonstrates that had Union (Enbridge) been the successful proponent to build the Southern Bruce system, its existing normalized average consumption account would have captured variances in actual consumption volume relative to those approved in rates. The fact that Union (Enbridge) has a variance account for customer volumes likewise demonstrates is it not a parameter that is susceptible to matters within the control of the utility.

74. EPCOR submits that the lack of connection between the Risk Sharing Mechanism and the incentive upon which it purports be justified demonstrates that the Risk Sharing Mechanism is in reality a punitive, as opposed to incentivizing, measure. As a punitive measure, it is not consistent with the Board's jurisdiction to set just and reasonable rates. While the Board has broad discretion in setting rates, this discretion must result in rates that are just and reasonable to both consumers and the utility.[58]

75. Therefore, the Risk Sharing Mechanism is not consistent with the Board's mandate to set just and reasonable rates and ought also to be set aside by the Board on that basis.

(b) The Board erred in determining the 300 basis points threshold was appropriate and provides an opportunity to provide a fair return

76. Further, the basis upon which the Board concluded that limiting recovery of the CVVA balances to the point that EPCOR's actual earnings reach 300 basis points below the ROE that underpinned EPCOR's CIP proposal and CIR is unreasonable.

[57] EB-2023-0140, Affidavit of Susannah Robinson (May 10, 2023), at para 19.
[58] *ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission)*, 2015 SCC 45, [2015] 3 SCR 219 at para 47.

77. In Decision EB-2022-0184, the Board pointed to three circumstances where it has imposed a -300 bp dead band; however, none of these are applicable to, or appropriate in, the circumstances of EPCOR. As established in the Decision EB-2016-0004, EPCOR's expansion of service to the South Bruce Municipalities is done on the basis of stand-alone rates to cover the cost of the expansion and subject to a 10-year rate stability period.[59] None of the situations identified by the Board where it has utilized the 300 basis point deadband were applied in analogous situations and in fact, two of these examples were expressly found to be inapplicable to EPCOR's expansion of service to the South Bruce Municipalities.

(a) First, the Board pointed to using 300 basis points as a means test regarding its policy regarding the recovery of the impacts arising from COVID-19.[60] As pointed out by EPCOR in its argument, the OEB determined that the COVID-19 deferral account guidelines were not approved for greenfield utilities such as EPCOR's South Bruce operation. In reaching this conclusion, the OEB stated that due to the unique circumstances of greenfield utilities, a generic application of the guidelines would be impractical.[61]

(b) Second, the Board pointed to the 300 basis point dead band as part of the OEB's ICM/ACM policy.[62] However, in EB-2018-0264, the Board concluded that ICM is not available for any matters related to the CIP during the 10-year rate stability period.[63]

(c) Third, the Board pointed to the 300 deadband also being used in considering the appropriateness of applying IRM increases.[64] The +/- 300 basis points variance from OEB-approved ROE applies to off-ramps and determines if a regulatory review is warranted in the context of electric distribution utilities subject to incentive rate-setting. The OEB's Filing Requirements for Electricity Distribution Rate Applications also provides that a distributor whose earnings are in excess of the deadband (i.e., in excess of +300 basis points over OEB-approved return) is

[59] *Generic Expansion Proceeding (EB-2016-0004) Decision*, pp 18 & 20.
[60] Decision EB-2022-0184, p 17.
[61] OEB EB-2020-0133 Proceeding, OEB Letter to Parties re: Consultation on the Deferral Account – Impacts Arising from the Covid-19 Emergency (April 13, 2021) pp 2-3.
[62] Decision EB-2022-0184, p 17.
[63] *2018-2019 CIRS (EB-2018-0264) Decision*, p 25.
[64] Decision EB-2022-0184, p 17.

> expected to refrain from seeking an adjustment to base rates through a Price Cap IR or Annual IR Index plan.[65] Neither of these are analogous to, nor relevant comparators to EPCOR. EPCOR is not an electric distribution utility. EPCOR is subject to a stand-alone 10-year rate stability period. Off-ramps were not put in place as part of the CIP and are not applicable to EPCOR's South Bruce extension of service. In EPCOR's CIR Application, the issue of off-ramps was specifically raised by OEB staff. As explained by EPCOR, the CIP competitive process imposes customer connection and cost risk on the utility as opposed to ratepayers but provides the utility with incentives to control costs and search for efficiencies as this could lead to an increased return. Therefore, the imposition of an earnings off-ramp is not consistent with the utility-ratepayer risk framework established in the CIP Proceeding.[66]

78. As is evident from the foregoing, the Board's finding that the -300 bp threshold for recovery of CVVA variances is "appropriate" and a "reasonable threshold" for EPCOR's South Bruce extension of service rates is simply not supportable. The Board's rationale for selecting that parameter is based on entirely dissimilar situations, some of which have been found specifically to be inapplicable. As such, the Board's conclusion that this limit on the recovery of balances in the CVVA "should provide EPCOR the opportunity to earn a fair rate of return" is completely without basis. The Board's conclusion in this regard amounts to an error of fact or mixed fact and law, in that the facts relied upon do not satisfy the legal test.[67]

79. Rather, the uncontroverted facts are that the imposition of the -300 bp limit will not provide EPCOR such an opportunity. Under the Board's Risk Sharing Mechanism, the possible achieved ROE is reduced to -1.8%, which is below an acceptable rate of return by any standards.[68]

80. As such, on this review, EPCOR respectfully submits that the Risk Sharing Mechanism should be set aside as the facts do not support that "provide EPCOR with the opportunity to earn a fair return" and the CVVA as applied-for by EPCOR should be approved.

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[65] Filing Requirements for Electricity Distribution Rate Applications, Chapter 3: Incentive Rate-Setting Applications (May 24, 2022), s 3.2.9, p 22-23.
[66] *2018-2019 (EB-2018-0264) CIRS Proceeding,* EPCOR Response to OEB 10.Staff.40 (July 5, 2019) at p 140.
[67] *Canada (Director of Investigation and Research) v Southam Inc.*[1997] 1 SCR 748 at para 35.
[68] EB-2023-0140, Affidavit of Susannah Robinson (May 10, 2023), at paras 25-26.

(c) An effective date of January 1, 2021 for the CVVA is permissible and appropriate

81. As part of its Application, EPCOR requested an effective date of January 1, 2021 for the CVVA. In EB-2022-0284, the Board approved an effective date of January 1, 2023, on the basis that to approve an earlier effective date would be retroactive ratemaking and there were no exceptional circumstances that would justify permitting retroactive ratemaking.

82. For the reasons that follow, EPCOR submits its proposed effective date of January 1, 2021 for the CVVA is both permissible and appropriate and the Board erred in determining otherwise.

83. In Decision EB-2022-0184, the OEB incorrectly found that an effective date for the CVVA of January 1, 2021, would amount to impermissible retroactive ratemaking.[69] The OEB endorsed OEB staff, SEC and VECC's argument that the presumption against retroactive ratemaking can only be considered in two circumstances, interim rates or a deferral and variance account, neither of which apply to EPCOR's specific circumstances.[70] In doing so, the OEB erred in fact and law by failing to consider years of other relevant precedent regarding the broader circumstances in which retroactive ratemaking is permissible and failing to correctly apply that law to EPCOR's unique circumstances.

84. In EB-2022-0184, the OEB acknowledged EPCOR's argument that several decisions have been critical of an overreliance on the interim rates and DVA exceptions,[71] but did not discuss the weight it gave, if any, to the decisions cited by EPCOR pointing to the existence of other exceptions to the presumption against retroactive ratemaking.

85. In *Union Gas Limited v Ontario Energy Board*[72]*,* the Ontario Court of Appeal, quoting the Alberta Court of Appeal in *ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission)* ("***ATCO***")*,* stated "[s]lavish adherence to the use of interim rates and deferral accounts should not prohibit adjustments" in a proper case.[73] In *ATCO*, the Alberta Court of Appeal also noted that it is not interim rates that are important *per se*, "[a]ccording to the Supreme Court of Canada in *Bell Canada 1989* at 1756, alteration of an interim rate by a regulator is simply a function of regulators

[69] Decision EB-2022-0184, p 11.
[70] Decision EB-2022-0184, p 9-10.
[71] Decision EB-2022-0184, p 10.
[72] *Union Gas Limited v Ontario Energy Board,* 2015 ONCA 453 [*Union Gas*].
[73] *Union Gas* at para 91 citing *ATCO Gas and Piplines Ltd. v. Alberta (Utilities Commission)* 2014 ABCA 28 [*ATCO*] at para 62.

who have the mandate to ensure rates and tariffs are, at all times, just and reasonable."[74] In *ATCO*, although there was no discussion of interim rates or deferral accounts, the Court found that ATCO was aware that its revenue requirement could change in the circumstances and therefore, the presumption against retroactive ratemaking did not apply.[75]

86. The Ontario Court of Appeal in *Union Gas* concluded that "[s]imply because a ratemaking decision has an impact on a past rate does not mean it is an impermissible retroactive decision".[76]

87. Similarly, in *Capital Power Corp. v. Alberta Utilities Commission* ("***Capital Power***"), the Alberta Court of Appeal provided a list of exceptions to the prohibition against retroactive ratemaking in addition to interim rates or deferral accounts, including:

> 3) changes to rates as a result of the operations of what is known as a negative disallowance scheme (where rates are set and charged by utilities subject to being later changed by the Commission because they were not "just and reasonable" in the first place);
>
> 4) changes to rates when affected parties knew or ought to have known that the rates were subject to change (the so-called "knowledge exception"); and
>
> 5) replacing rates in a tariff that have been determined to be a nullity.[77]

88. Importantly, the Alberta Court of Appeal also noted that this is <u>not</u> an exhaustive list of the recognized exemptions to the prohibition against retroactive ratemaking.[78] Ultimately, in *Capital Power*, the Alberta Court of Appeal indicated that there is no blanket prohibition against retroactive ratemaking. Rather, in exercising ratemaking authority, "the question is whether or not a strict application of the rule achieves sound utility regulation."[79] Retroactive ratemaking will be permissible where "considerations of fairness, reliance, rate stability and certainty are engaged and given more weight than countervailing considerations."[80] In that case, the Court found that the Commission's application of these regulatory principles indicated a retroactive remedy was in the public interest.[81]

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[74] *ATCO* at para 58.
[75] *ATCO* at para 61-63.
[76] *Union Gas* at para 91 citing *ATCO* at para 56; see also *EPCOR Energy Alberta GP Inc. 2021-2022 Non-Energy Regulated Rate Tariff Application* (AUC Decision 26694-D01-2022) at para 42.
[77] *Capital Power Corp. v. Alberta Utilities Commission* 2018 ABCA 437 [*Capital Power*] at para 57.
[78] *Capital Power* at para 57.
[79] *Capital Power* at para 66.
[80] *Capital Power* at para 65.
[81] See *Capital Power* at paras 66-67.

89. This type of analysis is more consistent with the OEB's broad mandate under the OEB Act to "make orders approving or fixing just and reasonable rates"[82] and in doing so, "adopt any method or technique that it considers appropriate" rather than a blanket ban on retroactive ratemaking or over-reliance on two rigid exceptions.

90. However, instead of considering whether, in EPCOR's specific circumstances, permitting an effective date of January 1, 2021 achieved sound utility regulation, the OEB confined itself to two of several recognized exceptions to retroactive ratemaking to find that neither applied in EPCOR's case. In doing so, the OEB appears to have relied on a single OEB decision cited by SEC - the OEB's decision in *Halton Hills Hydro Inc*. ("***Halton Hills***")[83] where the OEB denied retroactive application of a new DVA account.

91. Regardless, however, as EPCOR has previously stated, the facts surrounding the *Halton Hills* decision are distinguishable on several bases. There, the OEB found Halton Hills Hydro ("**HH**") had made an error in the calculation of depreciation expense in its last cost of service application, and appears to have accepted arguments from OEB staff and intervenors that there was no regulatory basis for HH's request under the OEB's rate-setting policies given its rates were set through a cost of service mechanism with annual adjustments, and HH had not demonstrated that its financial viability was at risk.[84] In contrast, the CVVA amounts are not the result of an EPCOR error, EPCOR's rates are based on an OEB-driven competitive process, and denial of EPCOR's proposed CVVA effective date of January 1, 2021 as compared to January 1, 2023 will result in a revenue shortfall of approximately $540,016.[85] Despite this, the OEB, did not address or adequately explain why the particular circumstances in this case warrant imposing this shortfall on EPCOR and how doing so would amount to the achieving sound utility regulation.

92. In reaching its decision in EB-2022-0184, the OEB should have considered all of the unique circumstances pertaining to EPCOR's rates, including the nature of the CIP application, EPCOR's entry into a previously unserved area, the calculation of customer common assumptions and the rationale behind the timing of EPCOR's CVVA application. The OEB ignored

[82] *Ontario Energy Board Act*, SO 1998, c 15, s 36(2).
[83] OEB Decision EB-2017-0045 [*Halton Hills*].
[84] *Halton Hills*, p 17-18.
[85] EB-2023-0140, Affidavit of Susannah Robinson (May 10, 2023) at Exhibit "A".

EPCOR's unique circumstances, and in doing so, failed to engage in a proper analysis of whether the presumption against retroactive ratemaking ought to govern.[86]

93. As a greenfield utility entering a previously unserved area with a starting customer base of zero, EPCOR did not have access to any historical customer usage data for the Southern Bruce region to set its rates in its CIR application.[87] The reality was that at the time the mass market customer consumption common assumption was determined, there was no existing gas utility servicing the South Bruce area. EPCOR's first customer was not connected until Q3 2020.[88] There was also no alternative assumption. Union Gas' normalized average for an adjacent service area was deemed an appropriate forecast.[89] No party involved in the competitive proceeding objected to this outcome.

94. EPCOR and the utility industry generally had limited experience in setting up a greenfield natural gas utility in Southern Ontario. Without any data to the contrary, EPCOR reasonably expected that forecast average customer volumes established through the CIP were sufficiently reliable.[90] EPCOR cannot be faulted for having this expectation; no other party involved in the competitive process thought or could have determined that there was a better average volume number.

95. In the interim, EPCOR continued in good faith to build out the distribution system according to the commitments made in its CIP, based on the revenue requirement determined using the common customer volumes.[91] South Bruce had very few customers connected in the first few years of operation, so there was not enough data to identify the impact of variances between actual and forecasted customer volumes.

96. EPCOR was unable to complete any meaningful analysis to confirm the existence of a shortfall between forecast customer volumes and actual customer volumes until 2022,[92] at which time EPCOR filed an application with the OEB for the CVVA. EPCOR sought a start date for

[86] *Capital Power* at para 65.
[87] *EPCOR 2023 Rates (EB-2022-0184) Proceeding*, Responses to Interrogatories (October 20, 2022), Response to VECC-1 [*EPCOR Responses to VECC-1*], p 13.
[88] *EPCOR Responses to VECC-1*, p 14.
[89] *EPCOR Responses to VECC-1*, pp 13-14.
[90] *EPCOR Responses to VECC-1*, pp 13-14.
[91] *EPCOR Responses to VECC-1*, p 13.
[92] *EPCOR Responses to VECC-1*, pp 14.

recording variances of January 1, 2021 for its CVVA because it is in proximity to when EPCOR began relying on revenue generated from common customer volumes.

97. The OEB in Decision EB-2022-0184 went so far as to characterize the presumption against retroactive ratemaking as a "rule" rather than a rebuttable presumption, indicating that "[t]he rule does not exist to reduce utility risk of financial impairment or to enable higher rates of return on invested capital."[93] This ignores the principle that rates must be just and reasonable from two perspectives – the perspective of the consumer and the perspective of the public utility.[94] In dollar terms, the OEB's denial of EPCOR's proposed CVVA effective date of January 1, 2021 as compared to January 1, 2023, will result in a revenue shortfall of approximately $540,016.[95] In contrast, the impact to residential customers if the OEB approved EPCOR's proposed effective date would result in an average increase to customer bills of approximately $11.25 per month (assuming collection over a single year in 2024), as set out below:[96]

Allocated CVVA Balance Per Residential Customer	
Allocated CVVA Balance – 2021 ($/cx)	$32
Allocated CVVA Balance – 2022 ($/cx)	$103
Total	$135
2021-2022 CCV Collection Impact Per Residential Customer (2024)	
2021-2022 CCVA Balance ($/cx)	$135
2021-2022 CCVA Balance ($/cx per month)	$11.25
CCVA % Impact to Bill (Non-distribution and Distribution)	8.95%

98. In the context of EPCOR's small, greenfield utility for the South Bruce expansion, a revenue shortfall of $540,016 is material. EPCOR submits that on balance the collection of this amount is reasonable, including in consideration of the bill impacts to customers (which for residential customers EPCOR has estimated as being approximately $11.25 per month over a 12 month period). In this regard, EPCOR submits that the Board should also consider that the OEB's competitive process shifted risk for capital cost overruns and customer attachment from

[93] Decision EB-2022-0184, p 10.
[94] See *Union Gas*, at para 25 citing *Power Workers' Union, Canadian Union of Public Employees, Local 1000* v. *Ontario (Energy Board),* 2013 ONCA 359, 116 O.R. (3d) 793, at paras 13, 30-32, leave to appeal to SCC granted, [2013] SCCA No. 339, appeal heard and reserved December 3, 2014; *Northwestern Utilities Ltd. v. Edmonton* (City), [1929] SCR 186, pp. 192-3.
[95] EB-2023-0140, Affidavit of Susannah Robinson (May 10, 2023) at Exhibit "A".
[96] These calculations were derived using the same workbook as used to respond to *EPCOR 2023 Rates (EB-2022-0184) Proceeding*, Responses to Interrogatories (October 20, 2022), Response to SEC-6, p 23, and updated to reflect the actual 2021 and 2022 disposition balances included in Exhibit-A of EB-2023-0140, Affidavit of Susannah Robinson (May 10, 2023).

customers to EPCOR, which EPCOR accepted full responsibility for.[97] As set out in the affidavit of Ms. Robinson, by honouring this regulatory compact, EPCOR has already assumed significant financial losses that cannot be recovered.[98]

99. However, as previously stated by EPCOR in EB-2022-0184, the utility is cognizant of bill impacts to customers arising from its recovery of balances in the CVVA and is supportive of taking steps to mitigate these impacts, including filing a rate smoothing proposal in the first application that it seeks disposition of the CVVA balance.[99] In terms of collecting CVVA balances from January 1, 2021 - December 31, 2022, one option would be for EPCOR to collect these amounts evenly over the remaining years in the 10-year rate stability term or longer, if directed by the Board.

100. The OEB's finding that retroactive ratemaking exists to protect customers fails to consider whether permitting the effective date of January 1, 2021 would nonetheless result in sound utility regulation. This position favours customer protection over a utility's ability to earn a return on investment and fails to acknowledge that for rates to be just and reasonable, the economic impacts to all market participants must be considered.

101. EPCOR respectfully submits that the OEB erred in fact and law in Decision EB-2022-0184 by denying EPCOR's proposed effective date of January 1, 2021 for the CVVA. As such, on this review, EPCOR respectfully submits that the effective date of January 1, 2023 for the CVVA should be set aside and an effective date of January 1, 2021 approved.

D. Relief Requested

102. EPCOR respectfully requests that in disposing of this this review application, the Board varying the Decision EB-2022-0184 as follows:

(a) set aside the Board's decision to limit EPCOR's recovery of the CVVA to 50% of the accumulated annual balance, until the point where EPCOR's actual earnings reach 300 basis points below its ROE; and

[97] *EPCOR 2023 Rates (EB-2022-0184) Proceeding*, EPCOR 2023 IRM Application, July 18, 2022, Table 1.2 CIP Competitive Parameters, p 26.
[98] EB-2023-0140, Affidavit of Susannah Robinson (May 10, 2023) at para.25.
[99] Decision EB-2022-0184, EPCOR Argument p 5; Decision EB-2022-0184, EPCOR Reply p. 20.

(b) approve the CVVA as applied-for by EPCOR, allowing it to fully track and recover annual balances in the CVVA resulting from the revenue difference between: (A) the average customer volume forecast based on the common assumptions set out in the common infrastructure plan; and (B) the actual average customer volume from January 1, 2021 until December 31, 2028.

All of which is respectfully submitted this 6th day of July, 2023.

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